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Substation Integration and Automation

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7.1 Introduction

Electric utility deregulation, economic pressures forcing downsizing, and the marketplace pressures of potential takeovers have forced utilities to examine their operational and organizational practices. Utilities are realizing that they must shift their focus to customer service. Customer service requirements all point to one key element: information — the right amount of information to the right person or computer within the right amount of time. The flow of information requires data communication over extended networks of systems and users. In fact, utilities are among the largest users of data and are the largest users of real-time information.

The advent of industry deregulation has placed greater emphasis on the availability of information, the analysis of this information, and the subsequent decision making to optimize system operation in a competitive environment. The intelligent electronic devices (IED) being implemented in today's substations contain valuable information, both operational and nonoperational, needed by many user groups

TABLE 7.1 Five-Layer Architecture for Substation Integration and Automation

Utility Enterprise Connection
Substation Automation Applications
IED Integration via Data Concentrator/Substation Host Processor
IED Implementation
Power System Equipment (Transformers, Breakers)

within the utility. The challenge facing utilities is determining a standard integration architecture that can meet the utility's specific needs; can extract the desired operational and nonoperational information; and can deliver this information to the users who have applications to analyze the information.

7.2 Definitions and Terminology

Substation integration and automation can be broken down into five levels, as seen in Table 7.1. The lowest level is the power system equipment, such as transformers and circuit breakers. The middle three levels are IED implementation, IED integration, and substation automation applications. All electric utilities are implementing IEDs in their substations. The focus today is the integration of the IEDs. Once this is done, the focus will shift to what automation applications should run at the substation level. The highest level is the utility enterprise, and there are multiple functional data paths from the substation to the utility enterprise. The five-layer architecture is shown in Table 7.1.

Since the substation integration and automation technology is fairly new, there are no industry standard definitions, except for the definition of an IED. The industry standard definition of an IED is given below, as well as definitions for IED integration and substation automation.

- Intelligent electronic device (IED): Any device incorporating one or more processors with the capability to receive or send data/control from or to an external source (e.g., electronic multifunction meters, digital relays, controllers) [2,10].
- IED integration: Integration of protection, control, and data acquisition functions into a minimal number of platforms to reduce capital and operating costs, reduce panel and control room space, and eliminate redundant equipment and databases.
- Substation automation: Deployment of substation and feeder operating functions and applications ranging from SCADA (supervisory control and data acquisition) and alarm processing to integrated volt/VAr control in order to optimize the management of capital assets and enhance operation and maintenance efficiencies with minimal human intervention.

7.3 Open Systems

An open system is a computer system that embodies supplier-independent standards so that software can be applied on many different platforms and can interoperate with other applications on local and remote systems. An open system is an evolutionary means for a substation control system that is based on the use of nonproprietary, standard software and hardware interfaces. Open systems enable future upgrades available from multiple suppliers at lower cost to be integrated with relative ease and low risk.

The concept of open systems applies to substation integration and automation. It is important to learn about the different *de jure* (legal) and *de facto* (actual) standards and then apply them so as to eliminate proprietary approaches. An open systems approach allows the incremental upgrade of the automation system without the need for complete replacement, as happened in the past with proprietary systems. There is no longer a need to rely on one supplier for complete implementation. Systems and IEDs from competing suppliers are able to interchange and share information. The benefits of open systems include longer expected system life, investment protection, upgradeability and expandability, and readily available third-party components.

TABLE 7.2 Three Functional Data Paths from Substation to Utility Enterprise

Utility Enterprise		
Operational Data-to-SCADA System	Nonoperational Data-to-Data Warehouse	Remote Access to IED
Substation Automation Applications		
IED Integration		
IED Implementation		
Power System Equipment (Transformers, Breakers)		

7.4 Architecture Functional Data Paths

There are three primary functional data paths from the substation to the utility enterprise, as seen in Table 7.2. The most common data path is conveying the operational data (e.g., volts, amps) to the utility’s SCADA system every 2 to 4 sec. This information is critical for the utility’s dispatchers to monitor and control the power system. The most challenging data path is conveying the nonoperational data to the utility’s data warehouse. The challenges associated with this data path include the characteristics of the data (not necessarily points but, rather, files and waveforms), the periodicity of data transfer (not continuous but, rather, on demand), and the protocols used to obtain the data from the IEDs (not standard but, rather, IED supplier’s proprietary protocols). Another challenge is whether the data are pushed from the substation into the data warehouse, or pulled from the data warehouse, or both. The third data path is remote access to an IED by “passing through” or “looping through” the substation integration architecture and isolating a particular IED in the substation.

7.5 Substation Integration and Automation System Functional Architecture

The functional architecture diagram in [Figure 7.1](#) shows the three functional data paths from the substation to the utility enterprise, as well as the SCADA system and the data warehouse. The operational data path to the SCADA system utilizes the communication protocol presently supported by the SCADA system. The nonoperational data path to the data warehouse conveys the IED nonoperational data from the substation automation (SA) system to the data warehouse, either being pulled by a data warehouse application from the SA system or being pushed from the SA system to the data warehouse based on an event trigger or time. The remote access path to the substation utilizes a dial-in telephone connection. The GPS (global positioning system) satellite clock time reference is shown, providing a time reference for the SA system and IEDs in the substation. The host processor provides the graphical user interface and the historical information system for archiving operational and nonoperational data. The SCADA interface knows which SA system points are sent to the SCADA system, as well as the SCADA system protocol. The LAN-enabled IEDs can be directly connected to the SA LAN (local area network). The non-LAN-enabled IEDs require a network interface module (NIM) for protocol and physical interface conversion. The IEDs can have various applications, such as equipment condition monitoring (ECM) and relaying, as well as direct (or hardwired) input/output (I/O).

7.6 New vs. Existing Substations

The design of new substations has the advantage of starting with a blank sheet of paper. The new substation will typically have many IEDs for different functions, and the majority of operational data for the SCADA system will come from these IEDs. The IEDs will be integrated with digital two-way communications. The small amount of direct input/output (hardwired) can be acquired using programmable logic controllers (PLC). Typically, there are no conventional remote terminal units (RTU) in new

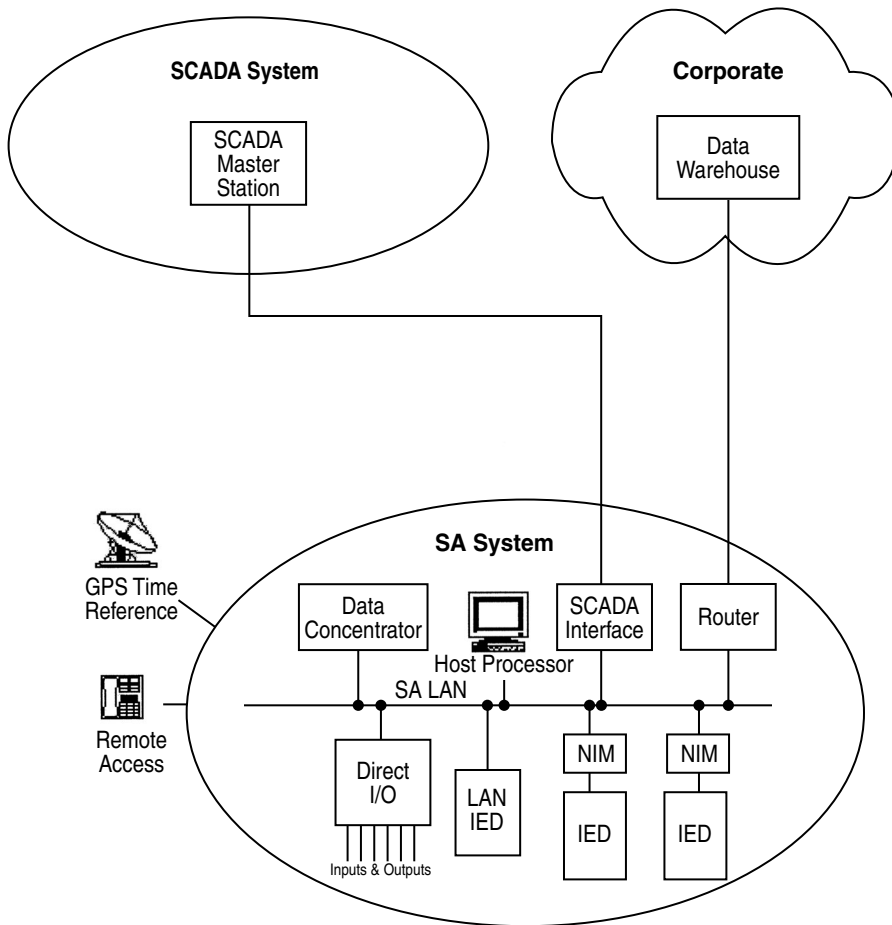


FIGURE 7.1 SA system functional architecture diagram.

substations. The RTU functionality is addressed using IEDs and PLCs and an integration network using digital communications.

In existing substations there are several alternative approaches, depending on whether the substation has a conventional RTU installed. The utility has three choices for their existing conventional substation RTUs: integrate RTU with IEDs; integrate RTU as another substation IED; and retire RTU and use IEDs and PLCs, as with a new substation. First, many utilities have integrated IEDs with existing conventional RTUs, provided the RTUs support communications with downstream devices and support IED communication protocols. This integration approach works well for the operational data path, but it does not support the nonoperational and remote access data paths. The latter two data paths must be done outside of the conventional RTU. Second, if the utility desires to keep their conventional RTU, the preferred approach is to integrate the RTU in the substation integration architecture as another IED. In this way, the RTU can be easily retired when the RTU hardwired direct input/output transitions to come primarily from the IEDs. Third, the RTUs may be old and difficult to support, and the substation automation project might be a good time to retire these older RTUs. The hardwired direct input/output from these RTUs would then come from the IEDs and PLCs, as with a new substation.

7.7 Equipment Condition Monitoring

Many electric utilities have employed equipment condition monitoring (ECM) to maintain electric equipment in top operating condition while minimizing the number of interruptions. With ECM,

equipment operating parameters are automatically tracked to detect the emergence of various abnormal operating conditions. This allows substation operations personnel to take timely action when needed to improve reliability and extend equipment life. This approach is applied most frequently to substation transformers and high-voltage electric supply circuit breakers to minimize the maintenance costs of these devices, to improve their availability, and to extend their useful life.

Equipment availability and reliability can be improved by reducing the amount of off-line maintenance and testing required and by reducing the number of equipment failures. To be truly effective, equipment condition monitoring should be part of an overall condition-based maintenance strategy that has been properly designed and integrated into the regular maintenance program.

ECM IEDs are being implemented by many utilities. In most implementations, the communication link to the IED is via a dial-up telephone line. To facilitate integrating these IEDs into the substation architecture, the ECM IEDs must support at least one of today's widely used IED protocols: Modbus, Modbus Plus, or DNP3 (distributed network protocol). In addition, a migration path to UCA[®]2 MMS is desired. If the ECM IEDs can be integrated into the substation architecture, the operational data will have a path to the SCADA system, and the nonoperational data will have a path to the utility's data warehouse. In this way, the users and systems throughout the utility that need this information will have access to it. Once the information is brought out of the substation and into the SCADA system and data warehouse, users can share the information in the utility. The "private" databases that result in islands of automation will go away. Therefore, the goal of every utility is to integrate these ECM IEDs into a standard substation integration architecture so that both operational and nonoperational information from the IEDs can be shared by utility users.

7.8 Substation Integration and Automation Technical Issues

There are many technical issues in substation integration and automation. These issues are discussed in this section in the following areas: system responsibilities, system architecture, substation host processor, substation LAN requirements, substation LAN protocols, user interface, communication interfaces, and the data warehouse.

7.8.1 System Responsibilities

The system must interface with all of the IEDs in the substation. This includes polling the IEDs for readings and event notifications. The data from all the IEDs must be sent to the utility enterprise to populate the data warehouse or be sent to an appropriate location for storage of the substation data. The system processes data and control requests from users and from the data warehouse. The system must isolate the supplier from the IEDs by providing a generic interface to the IEDs. In other words, there should be a standard interface regardless of the IED supplier. The system should be updated with a report-by-exception scheme, where status-point changes and analog-point changes are reported only when they exceed their significant deadband. This reduces the load on the communications channel. In some systems, the data are reported in an unsolicited response mode. When the end device has something to report, it does not have to wait for a poll request from a master (master to slave). The device initiates the communication by grabbing the communication channel and transmitting its information.

Current substation integration and automation systems perform protocol translation, converting all the IED protocols from the various IED suppliers. Even with the protocol standardization efforts going on in the industry, there will always be legacy protocols that will require protocol translation.

The system must manage the IEDs and devices in the substation. The system must be aware of the address of each IED, of alternate communication paths, and of IEDs that may be utilized to accomplish a specific function. The system must know the status of all connected IEDs at all times.

The system provides data exchange and control support for the data warehouse. It should use a standard messaging service in the interface (standard protocol). The interface should be independent of any IED protocol and should use a report-by-exception scheme to reduce channel loading.



FIGURE 7.2 Substation automation system.

The system must provide an environment to support user applications. These user applications can be internally written by the utility, or they can be purchased from a third party and integrated into the substation integration and automation system. Figure 7.2 is a photograph of a substation automation system.

7.8.2 System Architecture

The types of data and control that the system will be expected to facilitate are dependent on the choice of IEDs and devices in the system. This must be addressed on a substation-by-substation basis. The primary requirement is that the analog readings be obtained in a way that provides an accurate representation of their values.

The data concentrator stores all analog and status information available at the substation. This information is required for both operational and nonoperational reasons (e.g., fault-event logs, oscillography). There are three levels of data exchange and requirements associated with the substation integration and automation system.

7.8.2.1 Level 1 — Field Devices

Each electronic device (relay, meter, PLC, etc.) has internal memory to store some or all of the following data: analog values, status changes, sequence of events, and power quality. These data are typically stored in a FIFO (first in, first out) queue and vary in the number of events, etc., maintained.

7.8.2.2 Level 2 — Substation Data Concentrator

The substation data concentrator should poll each device (both electronic and other) for analog values and status changes at data collection rates consistent with the utility's SCADA system (e.g., status points every 2 sec, tie-line and generator analogs every 2 sec, and remaining analog values every 2 to 10 sec). The substation data concentrator should maintain a local database.



FIGURE 7.3 SCADA system dispatch center.

7.8.2.3 Level 3 — SCADA System, Data Warehouse

All data required for operational purposes should be communicated to the SCADA system via a communication link from the data concentrator, as seen in Figure 7.3. All data required for nonoperational purposes should be communicated to the data warehouse via a communication link from the data concentrator.

A data warehouse is necessary to support a mainframe or client-server architecture of data exchange between the system and corporate users over the corporate WAN (wide area network). This setup provides users with up-to-date information and eliminates the need to wait for access using a single line of communications to the system, such as telephone dial-up through a modem. [Figure 7.4](#) is a screenshot showing a network status display.

7.8.3 Substation Host Processor

The substation host processor must be based on industry standards and strong networking ability, such as Ethernet, X/Windows, Motif, TCP/IP, UNIX, Windows 2000, Linux, etc. It must also support an open architecture, with no proprietary interfaces or products. An industry-accepted relational database (RDB) with structured query language (SQL) capability and enterprise-wide computing must be supported. The RDB supplier must provide replication capabilities to support a redundant or backup database. A full-graphics user interface (bit or pixel addressable) should be provided with Windows-type capability. There should be interfaces to Windows-type applications (i.e., Excel, Access, etc.). The substation host processor should be flexible, expandable, and transportable to multiple hardware platforms (IBM, Dell, Sun, Compaq, HP, etc.). Should the host processor be single or redundant or distributed? For a smaller distribution substation, it can be a single processor. For a large transmission substation, there may be redundant processors to provide automatic backup in case of failure. Suppliers who offer a distributed processor system with levels of redundancy may be a more cost-effective option for the larger substations. PLCs can be used as controllers, running special application programs at the substation level, coded in ladder logic. Smaller secondary substations will have IEDs but may not have a host processor, instead using a data concentrator for IED integration. This setup lacks a user interface and historical data collection. The IED data from these secondary substations are sent upstream to a larger primary substation that contains

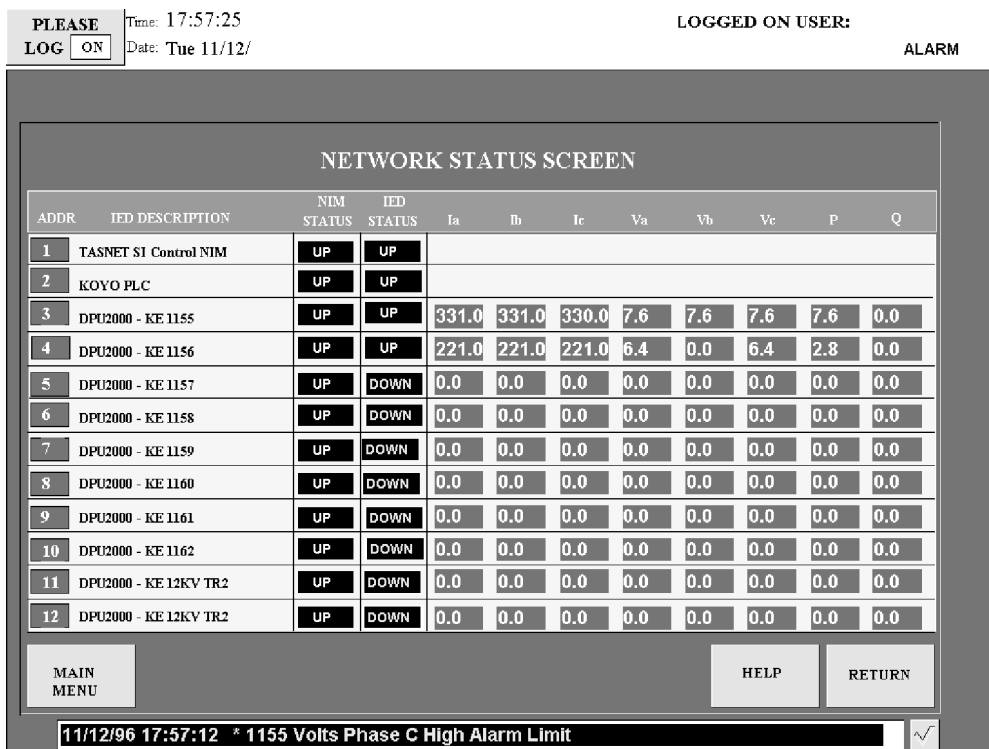


FIGURE 7.4 Network status display.

a complete substation integration and automation system. Figure 7.5 and Figure 7.6 illustrate primary and secondary integration and automation systems, respectively.

7.8.4 Substation Local Area Network (LAN)

7.8.4.1 LAN Requirements

The substation LAN must meet industry standards to allow interoperability and the use of plug-and-play devices. Open-architecture principles should be followed, including the use of industry standard protocols (e.g., TCP/IP, IEEE 802.x (Ethernet), UCA2). The LAN technology employed must be applicable to the substation environment and facilitate interfacing to process-level equipment (IEDs, PLCs) while providing immunity and isolation to substation noise.

The LAN must have enough throughput and bandwidth to support integrated data acquisition, control, and protection requirements. Should the LAN utilize deterministic protocol technologies, such as token ring and token bus schemes? Response times for data transfer must be deterministic and repeatable. (Deterministic: pertaining to a process, model, or variable whose outcome, result, or value does not depend on chance [10].)

The LAN should support peer-to-peer communications capability for high-speed protection functions as well as file-transfer support for IED configuration and PLC programs. (Peer-to-peer: communication between two or more network nodes in which either node can initiate sessions and is able to poll or answer to polls [10].) Priority data transfer would allow low-priority data such as configuration files to be downloaded without affecting time-critical data transfers. The IED and peripheral interface should be a common bus for all input/output. If the LAN is compatible with the substation computer (e.g., Ethernet), a front-end processor may not be needed. There are stringent speed requirements for interlocking and intertripping data transfer, which the LAN must support. The LAN must be able to support bridges and routers for the utility enterprise WAN interface. Test equipment for the LAN must be readily available and economical. Implementation of



FIGURE 7.5 Primary substation integration and automation system.

the LAN technology must be competitive to drive the cost down. For example, Ethernet is more widely used than FDDI, and therefore Ethernet interface equipment costs less.

Figure 7.7 illustrates the configuration of a substation automation system.

7.8.4.2 LAN Protocols

A substation LAN is a communications network, typically high speed, within the substation and extending into the switchyard. The LAN provides the ability to quickly transfer measurements, indications, control adjustments, and configuration and historic data between intelligent devices at the site. The benefits achievable using this architecture include: a reduction in the amount and complexity of the cabling currently required between devices; an increase in the available communications bandwidth to support faster updates and more advanced functions such as virtual connection, file transfer, peer-to-peer communications, and plug-and-play capabilities; and the less tangible benefits of an open LAN architecture, which include laying the foundation for future upgrades, access to third-party equipment, and increased interoperability.



FIGURE 7.6 Secondary substation integration and automation system.

The EPRI-sponsored Utility Substation Communication Initiative performed benchmark and simulation testing of different LAN technologies for the substation in late 1996. The initial substation configuration tested included 47 IEDs with these data types: analog, accumulator, control and events, and fault records. The response requirements were 4 msec for a protection event, 111 transactions per second for SCADA traffic, and 600 sec to transmit a fault record. The communication profiles tested were FMS/Profibus at 12 Mbps, MMS/Trim7/Ethernet at 10 Mbps and 100 Mbps, and switched Ethernet. Initially, the testing was done with four test-bed nodes using four 133-MHz Pentium computers. The four nodes simulated 47 devices in the substation. Analysis of the preliminary results from this testing resulted in a more extensive follow-up test done with 20 nodes using 20 133-MHz Pentium computers. The 20 nodes simulated a large substation issuing four trip signals each to simulate eighty trip signals from eighty different IEDs.

The tests determined that FMS/Profibus at 12 Mbps (fast FMS implementation) could not meet the trip time requirements for protective devices. However, MMS/Ethernet did meet the requirements. In addition, it was found that varying the SCADA load did not impact transaction performance. Moreover, the transmission of oscillographic data and SCADA data did not impact transaction times.

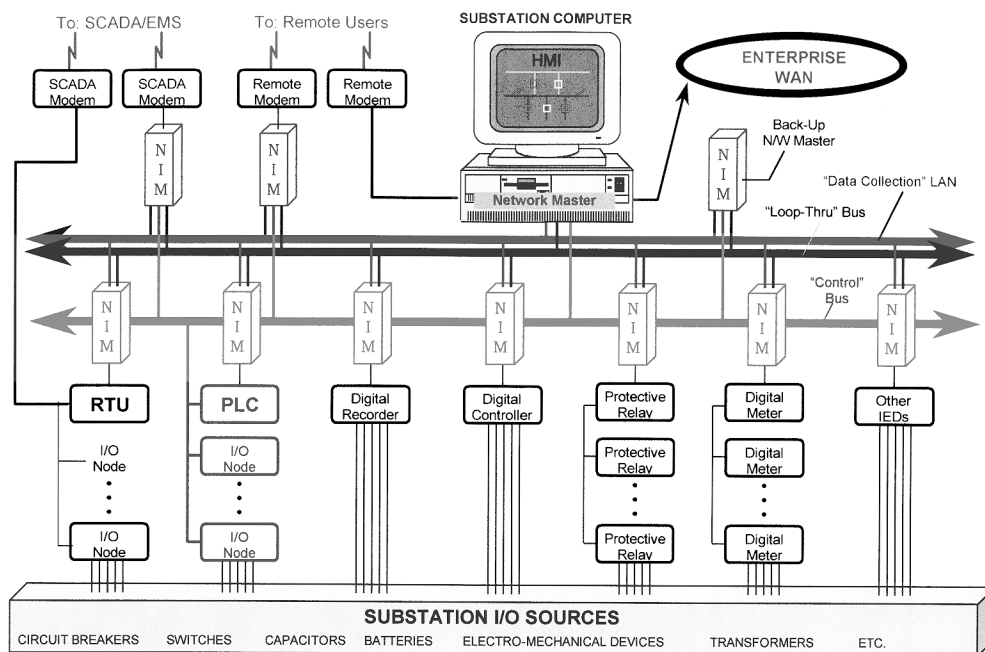


FIGURE 7.7 Configuration of substation automation system. (From National Rural Electric Cooperative Association, *Automating a Distribution Cooperative, from A to Z*, NRECA Cooperative Research Network, Arlington, VA, 1999. With permission.)

7.8.5 User Interface

The user interface in the substation must be an intuitive design to ensure effective use of the system with minimal confusion. An efficient display hierarchy will allow all essential activities to be performed from a few displays. It is critical to minimize or, better yet, eliminate the need for typing. There should be a common look and feel established for all displays. A library of standard symbols should be used to represent substation power apparatus on graphical displays. In fact, this library should be established and used in all substations and coordinated with other systems in the utility, such as the distribution SCADA system, the energy management system, the geographic information system (GIS), the trouble call management system, etc. The field personnel, or the users of the system, should be involved in determining what information should be on the different displays. Multiple databases should be avoided, such as a database for an IED associated with a third-party user-interface software package (e.g., U.S. Data FactoryLink, BJ Systems RealFlex, Intellution, Wonderware, etc.).

The substation one-line displays may be similar in appearance to the displays on a distribution management system or an energy management system. Figure 7.8 shows a typical substation one-line display. The functionality of an analog panel meter is typically integrated in the user interface of the substation automation system. The metered values can be viewed in a variety of formats. Alarm displays can have tabular and graphical display formats. There should be a convenient means to obtain detailed information about the alarm condition. Figure 7.9 shows a typical substation alarm display.

There are two types of logs in the substation. The substation integration and automation system has the capability of logging any information in the system at a specified periodicity. It can log alarms and events with time tags. In other words, any information the system has can be included in a log. A manual log is also in the substation for documenting all activities performed in the substation. The information in the manual log can be included in the system, but it would have to be entered into the system using the keyboard, and typing is not something field personnel normally want to do.

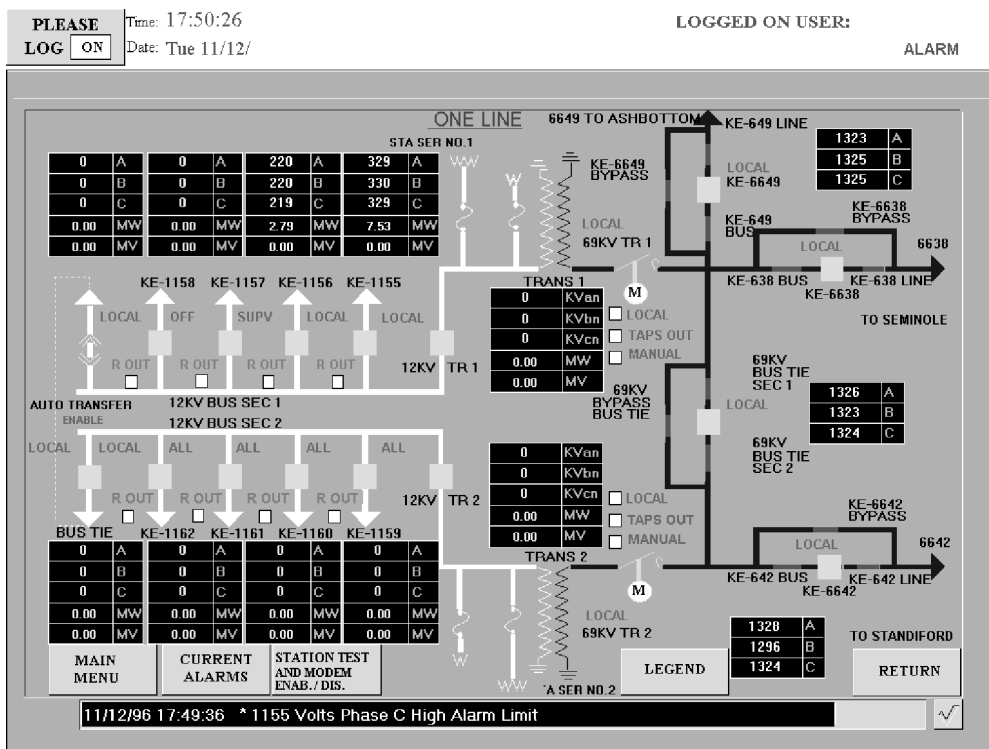


FIGURE 7.8 Substation one-line display.

7.8.6 Communication Interfaces

There are interfaces to substation IEDs to acquire data, determine the operating status of each IED, support all communication protocols used by the IEDs, and support standard protocols being developed. There may be an interface to the energy management system (EMS) that allows system operators to monitor and control each substation and the EMS to receive data from the substation integration and automation system at different periodicities. There may be an interface to the distribution management system with the same capabilities as the EMS interface. There may also be an interface to a capacitor control system that allows (a) control of switched capacitor banks located on feeders emanating from the substation, (b) monitoring of VARs on all three phases for the decision to switch the capacitor bank, and (c) verification that the capacitor bank did switch. There is always an interface for remote access capabilities — providing authorized access to the system via dial-in telephone or a secure network connection — to obtain data and alarms, execute diagnostic programs, and retrieve results of diagnostic programs. Lastly, there is an interface to a time-standard source. A time reference unit (TRU) is typically provided at each substation for outputting time signals to the substation integration and automation system IEDs, controllers, and host computers. The GPS time standard is used and synchronized to GPS satellite time. The GPS system includes an alphanumeric display for displaying time, satellite tracking status, and other setup parameters.

7.8.7 Data Warehouse

The data warehouse enables users to access substation data while maintaining a firewall to protect substation control and operation functions. (A firewall protects a trusted network from an outside, “untrusted” network — a difficult job to do quickly and efficiently, since the firewall must inspect each network communication and decide whether to allow it to cross over to the trusted network [18].) Both

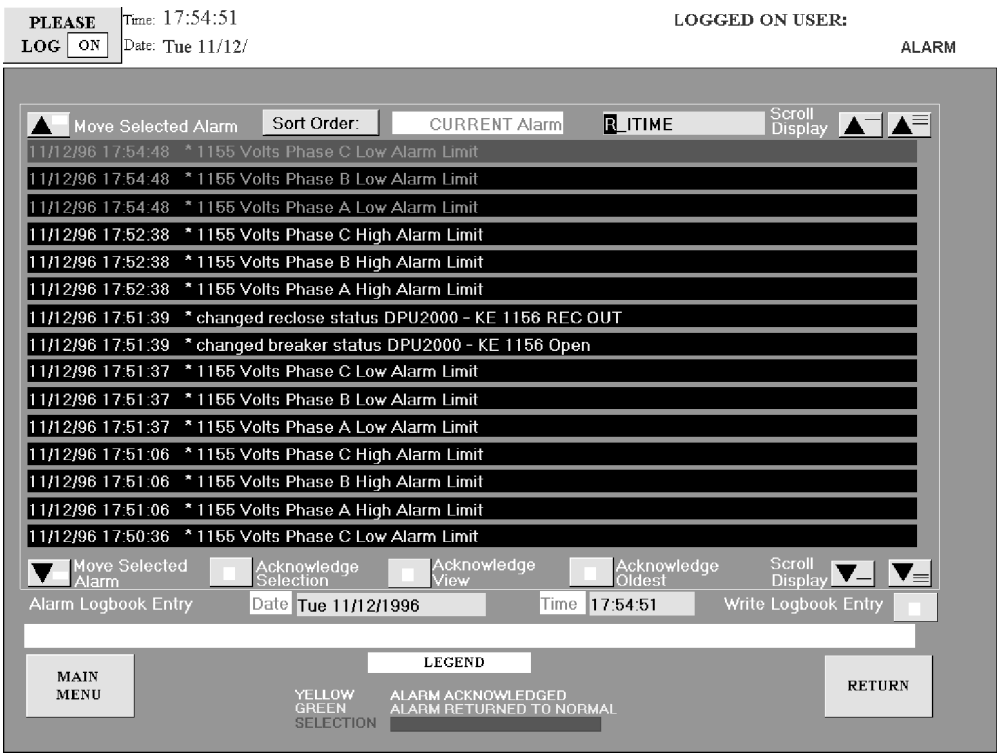


FIGURE 7.9 Substation alarm display.

operational and nonoperational data (e.g., fault-event logs, oscillographic data) are needed in the data warehouse. The utility must determine who will use the substation automation system data, the nature of their application, the type of data needed, how often the data are needed, and the frequency of update required for each user. Examples of user groups within a utility are operations, planning, engineering, SCADA, protection, distribution automation, metering, substation maintenance, and information technology. A possible data warehouse is the information management system (IMS) typically associated with an energy management system (EMS). The IMS is populated by the EMS with both real-time and historical data and uses firewalls to prevent external access beyond the IMS into the EMS.

7.9 Protocol Fundamentals

A communication protocol allows communication between two devices. The devices must have the same protocol (and version) implemented. Any protocol differences will result in communication errors.

If the communication devices and protocols are from the same supplier, i.e., where a supplier has developed a unique protocol to utilize all the capabilities of the two devices, it is unlikely the devices will have trouble communicating. By using a unique protocol of one supplier, a utility can maximize the device's functionality and see a greater return on its investment. However, the unique protocol will constrain the utility to one supplier for support and for purchase of future devices.

If the communication devices are from the same supplier but the protocol is an industry standard protocol supported by the device supplier, the devices should not have trouble communicating. The device supplier has designed its devices to operate with the standard protocol and communicate with other devices using the same protocol and version. By using a standard protocol, the utility can purchase equipment from any supplier that supports the protocol and can therefore comparison-shop for the best prices.

Industry standard protocols typically require more overhead than a supplier's unique protocol. Standard protocols often require a higher-speed channel than a supplier's unique protocol for the same

efficiency or information throughput. However, high-speed communication channels are more prevalent today and can provide adequate efficiency when using industry standard protocols. UCA2 MMS is designed to operate efficiently over 10 Mbps switched, or 100 Mbps shared, or switched Ethernet. If a utility is considering UCA2 MMS as its protocol of choice, a prerequisite should be installation of high-speed communications. If the utility's plan is to continue with a communication infrastructure operating at 1200 to 9600 bps the better choice for an industry standard protocol would be DNP3.

A utility may not be able to utilize all of a device's functionality using an industry standard protocol. If a device was designed before the industry standard protocol, the protocol may not thoroughly support the device's functionality. If the device was designed after the industry standard protocol was developed, the device should have been designed to work with the standard protocol such that all of the device's functionality is available.

The substation integration and automation architecture must allow devices from different suppliers to communicate (interoperate) using an industry standard protocol. Using an industry standard protocol, where suppliers have designed their devices to achieve full functionality with the protocol, a utility has the flexibility to choose the best devices for each application. Though devices from different suppliers can operate and communicate under the standard protocol, each device may have capabilities not supported by another device. There is also risk that the implementations of the industry standard protocol by the two suppliers in each device may have differences. Factory testing will verify that the functions of one device are supported by the protocol of the other device and vice versa. If differences and/or incompatibilities are found, they can be corrected during factory testing.

7.10 Protocol Considerations

There are two capabilities a utility considers for an IED. The primary capability of an IED is its stand-alone capabilities, such as protecting the power system for a relay IED. The secondary capability of an IED is its integration capabilities, such as its physical interface (e.g., RS-232, RS-485, Ethernet) and its communication protocol (e.g., DNP3, Modbus, UCA2 MMS).

Utilities typically specify the IEDs they want to use in the substation rather than giving a supplier a turnkey contract to provide only that supplier's IEDs in the substation. However, utilities typically choose an IED based on its stand-alone capabilities, without considering the IED's integration capabilities. Once the IEDs are installed, the utility may find it difficult to migrate to an integrated system if the IEDs were purchased with the supplier's proprietary protocol and with an undesirable physical interface (e.g., RS-485 purchased when Ethernet is desired). When purchasing IEDs the utility must consider both the stand-alone capabilities and the integration capabilities, even if the IEDs will not be integrated in the near future.

The most common IED communication protocols are Modbus, Modbus Plus, and DNP3. The UCA2 MMS protocol is becoming commercially available from more IED suppliers, and it is being implemented in more utility substations. However, the implementations may not be optimal if the UCA functionality is not built into the IED. In such cases, the utility must add a separate box for the UCA2 MMS protocol apart from the Ethernet network, and this can result in poor performance because of data latency due to the additional box. The utility must be cautious when ordering an IED for use in a system using a protocol other than the supplier's (often proprietary) target protocol, since some IED functionality may be lost. The most common IED networking technology today in substations is serial communications, either RS-232 or RS-485. As more and more IEDs become available with Ethernet ports, the IED networking technology in the substation will be primarily Ethernet.

7.10.1 Utility Communications Architecture (UCA)

The use of international protocol standards is now recognized throughout the electric utility industry as a key to successful integration of the various parts of the electric utility enterprise. Efforts to standardize the protocols that facilitate substation integration and automation have taken place within the framework provided by the Electric Power Research Institute's (EPRI) UCA.

UCA is a standards-based approach to utility data communications that provides for wide-scale integration from the utility enterprise level (as well as between utilities) down to the customer interface, including distribution, transmission, power plant, control center, and corporate information systems. The UCA Version 1.0 specification was issued in December 1991 as part of EPRI Project RP2949, Integration of Utility Communication Systems. While this specification supplied a great deal of functionality, industry adoption was limited, due in part to a lack of detailed specifications about how the specified protocols would actually be used by applications. For example, the manufacturing messaging specification (MMS) ISO/IEC 9506 protocol was specified for real-time data exchange at many levels within a utility. Unfortunately, the protocol did not have specific mappings to MMS for exchanging power system data and schedules or for communicating directly with substation or distribution feeder devices. The result was a continuation in interoperability problems.

The UCA (MMS) forum was started in May 1992 to address these UCA application issues. Six working groups were established to consider issues of MMS application in power plants, control centers, customer interface, substation automation, distribution feeder automation, and profile issues. The MMS forum served as a mechanism for utilities and suppliers to build the technical agreements necessary to achieve a wide range of interoperability using UCA MMS. Out of these efforts came the notion of defining standard power system objects and mapping them onto the services and data types supported by MMS and the other underlying standard protocols. This heavily influenced the definition of the UCA Version 2.0 specification issued in late 1996, which endorses ten different protocol profiles, including transmission control protocol/Internet protocol (TCP/IP) and intercontrol center communications protocol (ICCP), as well as a new set of common application service models for real-time device access.

The EPRI UCA/Substation Automation Project began in the early 1990s to produce industry consensus regarding substation integrated control, protection and data acquisition, and interoperability of substation devices from different manufacturers. The Substation Protocol Reference Specification recommended three of the ten UCA2 profiles for use in substation automation. Future efforts in this project were integrated with the efforts in the Utility Substations Initiative described below.

In mid-1996 American Electric Power hosted the first Utility Substations Initiative meeting as a continuation of the EPRI UCA/Substation Automation Project. Approximately 40 utilities and 25 suppliers are presently participating, having formed supplier/utility teams to define the supplier IED functionality and to implement a standard IED protocol (UCA2 profile) and LAN protocol (Ethernet).

Generic object models for substation and feeder equipment (GOMSFE) are being developed to facilitate suppliers in implementing the UCA/Substation Automation Project's substation and feeder elements of the power-system object model. New IED products with this functionality are now commercially available. The Utility Substations Initiative meets three times each year, in January, May, and September, immediately following the IEEE PES Power System Relaying Committee (PSRC) meetings and in conjunction with the UCA Users Group meetings. Every other meeting includes a supplier interoperability demonstration. The demonstration in September 2002 involved approximately 20 suppliers with products interconnected by a fiber Ethernet LAN interoperating with the UCA2 MMS protocol, the GOMSFE device object models, and Ethernet networks.

The UCA Users Group is a nonprofit organization whose members are utilities, suppliers, and users of communications for utility automation. The mission of the UCA Users Group is to enable utility integration through the deployment of open standards by providing a forum in which the various stakeholders in the utility industry can work together cooperatively as members of a common organization. The group's goals are to:

- Influence, select, and endorse open and public standards appropriate to the utility market based on the needs of the membership
- Specify, develop, and accredit product/system-testing programs that facilitate the field interoperability of products and systems based upon these standards
- Implement educational and promotional activities that increase awareness and deployment of these standards in the utility industry

The UCA Users Group was first formed in 2001 and presently has 34 corporate members, including 17 suppliers, 14 electric utilities, and 3 consultants and other organizations. The UCA Users Group organization consists of a board of directors, with the executive committee and technical committee reporting to the board. The executive committee has three committees reporting to it: marketing, liaison, and membership. The technical committee has a number of subcommittees reporting to it, including substation, communications, products, object models (IEC 61850/GOMSFE), and test procedures. The web site for the UCA Users Group is www.ucausersgroup.org. The UCA Users Group meets three times each year, in January, May, and September, immediately following the IEEE PES PSRC meetings and in conjunction with the UCA Users Group meetings. In addition, the UCA Users Group met at the IEEE PES Substations Committee Annual Meeting April 27–30, 2003, in Sun Valley, Idaho. This meeting included a supplier interoperability demonstration, with 20 suppliers demonstrating the implementation of the UCA2 MMS protocol and Ethernet networking technology into their IEDs and products, and interoperating with the other suppliers' equipment.

7.10.2 International Electrotechnical Commission (IEC) 61850

The UCA2 substation automation work has been brought to IEC Technical Committee (TC) 57 Working Groups (WG) 10, 11, and 12, who are developing IEC 61850, the single worldwide standard for substation automation communications. IEC 61850 is based on both UCA2 and European experience and provides additional functions such as substation configuration language and a digital interface to nonconventional current and potential transformers.

7.10.3 Distributed Network Protocol (DNP)

The development of the distributed network protocol (DNP) was a comprehensive effort to achieve open, standards-based interoperability between substation computers, RTUs, IEDs, and master stations (except intermaster station communications) for the electric utility industry. DNP is based on the standards of the IEC TC 57, WG 03. DNP has been designed to be as close to compliant as possible to the standards as they existed at time of development with the addition of functionality not identified in Europe but needed for current and future North American applications (e.g., limited transport-layer functions to support 2K block transfers for IEDs as well as radio frequency [RF] and fiber support). The present version of DNP is DNP3, which is defined in three distinct levels. Level 1 has the least functionality (for simple IEDs), and Level 3 has the most functionality (for SCADA master station-communication front-end processors).

The short-term benefits of using DNP are interoperability between multi-supplier devices; fewer protocols to support in the field; reduced software costs; no protocol translators needed; shorter delivery schedules; less testing, maintenance, and training; improved documentation; independent conformance testing; and support by independent user group and third-party sources (e.g., test sets, source code). In the long-term, further benefits can be derived from using DNP, including easy system expansion; long product life; more value-added products from suppliers; faster adoption of new technology; and major operations savings.

DNP was developed by Harris, Distributed Automation Products, in Calgary, Alberta, Canada. In November 1993 responsibility for defining further DNP specifications and ownership of the DNP specifications was turned over to the DNP User Group, a group composed of utilities and suppliers who are utilizing the protocol. The DNP User Group is a forum of over 300 users and implementers of the DNP3 protocol worldwide. The major objectives of the user group are to maintain control of the protocol and determine the direction in which the protocol will migrate; to review and add new features, functions, and enhancements to the protocol; to encourage suppliers and utilities to adopt the DNP3 protocol as a standard; to define recommended protocol subsets; to develop test procedures and verification programs; and to support implementer interaction and information exchange. The DNP User Group has an annual general meeting in North America, usually in conjunction with the DistribuTECH Conference

in January/February. The web site for DNP and the DNP User Group is www.dnp.org. The DNP User Group Technical Committee is an open volunteer organization of industry and technical experts from around the world. This committee evaluates suggested modifications or additions to the protocol and then amends the protocol description as directed by the user group members.

7.11 Choosing the Right Protocol

There are several factors to consider when choosing the right protocol for your application. First, determine the system area you are most concerned with, e.g., the protocol from a SCADA master station to the SCADA RTUs, a protocol from substation IEDs to an RTU or a PLC, or a local area network in the substation. Second, determine the timing of your installation, e.g., 6 months, 18 to 24 months, or 3 to 5 years. In some application areas, technology is changing so quickly that the timing of your installation can have a great impact on your protocol choice. If you are implementing new IEDs in the substation and need them to be in service in 6 months, you could narrow your protocol choices to DNP3, Modbus, and Modbus Plus. These protocols are used extensively in IEDs today. If you choose an IED that is commercially available with UCA2 MMS capability today, then you can choose UCA2 MMS as your protocol.

If your time frame is 1 to 2 years, you should consider UCA2 MMS as the protocol. Monitor the results of the Utility Substation Communication Initiative utility demonstration sites. These sites have implemented new supplier IED products that are using UCA2 MMS as the IED communication protocol and Ethernet as the substation local area network.

If your time frame is near term (6 to 9 months), make protocol choices from suppliers who are participating in the industry initiatives and are incorporating this technology into their product's migration paths. This will help protect your investment from becoming obsolete by allowing incremental upgrades to new technologies.

7.12 Communication Protocol Application Areas

There are various protocol choices, depending on the protocol application area of your system. Protocol choices vary with the different application areas, which are in different stages of protocol development and levels of industry efforts. The status of development efforts for different applications will help determine realistic plans and schedules for your specific projects.

7.12.1 Within the Substation

The need for a standard IED protocol dates back to the late 1980s. IED suppliers acknowledge that their expertise is in the IED itself – not in two-way communications capability, the communications protocol, or added IED functionality from a remote user. Though the industry made some effort to add communications capability to the IEDs, each IED supplier was concerned that any increased functionality would compromise performance and drive the IED cost so high that no utility would buy it. Therefore, the industry vowed to keep costs competitive and performance high as standardization was incorporated into the IED.

The IED suppliers' lack of experience in two-way communications and communication protocols resulted in crude, primitive protocols and, in some cases, no individual addressability and improper error checking (no select-before-operate). Each IED required its own communication channel, but only limited channels, if any, were available from RTUs. SCADA system and RTU suppliers were pressured to develop the capability to communicate with IEDs purchased by the utilities. Each RTU and IED interface required not only a new protocol, but a proprietary protocol not used by any other IED.

It was at this point that the Data Acquisition, Processing and Control Systems Subcommittee of the IEEE PES Substations Committee recognized the need for a standard IED protocol. The subcommittee formed a task force to examine existing protocols and determine, based on two sets of screening criteria,

the two best candidates. IEEE Standard 1379, Trial Use Recommended Practice for Data Communications between Intelligent Electronic Devices and Remote Terminal Units in a Substation, was published in March 1998. This document did not establish a new communication protocol. To quickly achieve industry acceptance and use, it instead provided a specific implementation of two existing communication protocols in the public domain, DNP3 and IEC 870-5-101.

For IED communications, if your implementation time frame is 6 to 9 months, select from protocols that already exist — DNP3, Modbus, and Modbus Plus. However, if the implementation time frame is 1 year or more, consider EPRI UCA2 with MMS as the communications protocol. Regardless of your time frame, evaluate each supplier's product migration plans. Try to determine if the system will allow migration from today's IED with DNP3 to tomorrow's IED with EPRI UCA2 MMS without replacing the entire IED. This will leave open the option of migrating the IEDs in the substation to EPRI UCA2 in an incremental manner, thus avoiding wholesale replacement. If you choose an IED that is commercially available with UCA2 MMS capability today, then you may want to choose UCA2 MMS as your IED protocol.

7.12.2 Substation-to-Utility Enterprise

This is the area of traditional SCADA communication protocols. The Data Acquisition, Processing and Control Systems Subcommittee of the IEEE PES Substations Committee began developing a recommended practice in the early 1980s in an attempt to standardize master/remote communications practices. At that time, each SCADA system supplier had developed a proprietary protocol based on technology of the time. These proprietary protocols exhibited varied message structures, terminal-to-data circuit terminating equipment (DCE) and DCE-to-channel interfaces, and error detection and recovery schemes. The IEEE Recommended Practice for Master/Remote Supervisory Control and Data Acquisition (SCADA) Communications (IEEE Std. 999-1992) addressed this nonuniformity among the protocols, provided definitions and terminology for protocols, and simplified the interfacing of more than one supplier's RTUs to a master station.

The major standardization effort undertaken in this application area has taken place in Europe as part of the IEC standards-making process. The effort resulted in the development of the IEC 870-5 protocol, which was slightly modified by GE (Canada) to create DNP. This protocol incorporated a pseudo transport layer, allowing it to support multiple master stations. The goal of DNP was to define a generic standards-based (IEC 870-5) protocol for use between IEDs and data concentrators within the substation, as well as between the substation and the SCADA system control center. Success led to the creation of the supplier-sponsored DNP User Group that currently maintains full control over the protocol and its future direction. DNP3 has become a *de facto* standard in the electric power industry and is widely supported by suppliers of test tools, protocol libraries, and services.

7.13 Summary

As we look to the future, it seems the time between the present and the future is shrinking! When a PC bought today is made obsolete in 6 months by a new model with twice the performance at less cost, how can you protect the investments in technology you make today? Obviously, there is no way you can keep up on a continuous basis with all the technology developments in all areas. You must rely on others to keep you informed, and who you select to keep you informed is critical. With every purchase, you must evaluate not only the supplier's present products, but also its future product development plans. Does the supplier continuously enhance and upgrade products? Is the supplier developing new products to meet future needs? Do existing products have a migration path to enhanced and new products? Selecting the right supplier will ensure you stay informed about new and future industry developments and trends and will allow you to access new technologies that will improve your current operation.

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